Attachment B

An Assessment of
Major Utility Air Emission Control and Cost

I. Introduction

There are four electric utilities in Wisconsin that are significant sources of atmospheric mercury each emitting 100 pounds or more of mercury annually, based on historic reporting of their emissions. These four “major” electric utilities include Alliant Energy (AE), Dairyland Power Cooperative (DPC), WE Energies (WE) and Wisconsin Public Service Corporation (WPSC). This assessment concerns the projected application of control technology to determine the amount of mercury emission reductions that can be achieved from the 42 coal-fired boilers these major utilities operate. A specific “surrogate” control technology has been identified even though it is recognized that there may be other techniques that may be equally as effective in controlling mercury emissions. The surrogate technology evaluated in this assessment has been the focus of intense development by organizations recognized for their work in mercury control technology and it is likely to receive widespread application on electric utility coal-fired boilers in the near future.

This assessment considers two different applications of this technology that involve the injection of activated carbon into the exhaust gas of a coal-fired boiler. Also, in this assessment is a projected schedule for installation of this technology that considers the need for engineering and planning to ensure good mercury control equipment performance and that avoids disruption of electrical service during the installation on individual units as well as to an entire utility system.

The four major utilities have historically controlled mercury emissions by an average of 13%, resulting in annual emissions of approximately 2,400 pounds, in the five-year period from 1997 through 2001. It is expected that by 2008, based on anticipated equipment and operational changes, average mercury control will increase to approximately 19% with annual emissions of approximately 2,260 pounds from the four utilities.

The projected schedule for the installation of the surrogate technology in this assessment result in additional mercury emission reductions commencing in 2010 and culminating in 2015. Beginning in 2010 each major utility would have one of their large units, greater than 200 megawatts (MW), equipped with activated carbon injection with polishing fabric filter, one form of the surrogate technology. As a result, mercury emissions from the four major utilities would be reduced an average of 47% with the range among the utilities from 38% to 66%. In 2015, after completion of surrogate technology installation, average mercury emissions would be reduced by 88%, with little variation among the four major utilities. To achieve this level of control 17 of 42 coal-fired generation units currently operating would be equipped with the form of the surrogate technology that includes activated carbon injection with a polishing fabric filter. With a few exceptions these are units that are larger than 200 MW. The remaining 25 units, all 200 MW or less, would be equipped with the second form of the surrogate technology, activated carbon injection.

A dedicated fabric filter system maintains reuse of 95% of the fly ash generated for each unit using this surrogate technology. The activated carbon injection system alone applied to the small units result in all fly ash becoming unusable as a cement additive. Currently, the fly ash generated by the smaller units is of lower quality and generally not reused.

The estimated cost range for surrogate control technology installation for all major utilities in 2010 is between 28 to 33 million dollars per year. By 2015, the cost range increases to between 87 to 104 million dollars per year. For the residential household this results in an estimated added cost of 6 to 7 dollars per year in 2010 and 18 to 21 dollars per year in 2015. The estimated cost to the average commercial customer is 37 to 44 dollars per year in 2010 and 116 to 138 dollars per year in 2015. The average commercial customer has significantly higher electric consumption per year than the residential customer does. The estimated cost for an industrial customer is expressed in cost for every thousand dollars of net proceeds or of the value of shipped product in 1996. On this basis, the cost range is 0.28 to 0.33 dollars per $1000 net proceeds in 2010 and 0.88 to 1.05 dollars per $1000 net proceeds in 2015.

II. Estimate of Major Utility Mercury Emissions and Mercury Control

The purpose of this assessment is to determine the effectiveness and costs of using a specific technology to limit mercury emissions from coal-fired utility boilers in Wisconsin. In order to perform that assessment it is necessary to establish a fundamental understanding of mercury emissions and the level of mercury control that is being achieved by existing units at the four major electric utilities that are being considered for regulation. Included in this section is a summary of the following data that establishes a foundation for the analysis of the surrogate mercury control technology under consideration:

- Inventory of coal-fired units at the major utilities and their utilization.
- Estimate of mercury emissions and mercury control during the period 1997-2001.
- Projection of the amount of mercury emissions and level of mercury control that will be achieved by 2008 prior to installation of surrogate control technology.

Also included below is a brief summary of the current understanding of mercury emissions from utility coal combustion and the factors that affect the ability of the surrogate technology to effectively control mercury emissions.

Background for Estimating Mercury Emissions and Mercury Control

Since 1992, Wisconsin facilities emitting more than 18 pounds per year of hazardous air pollutants, including mercury, have been required to report annual emissions to the Department under chapter NR 438, Wis. Adm. Code. However, the Department's reporting requirement does not always specify the methods to calculate emissions of many of these contaminants. Emission estimates are often based on generalized and limited fuel content and emissions data. Therefore, even though reported mercury emissions data was readily available for coal-fired electric utility plants, in general, the emission estimates were inconsistent and did not always reflect the likely reduction that is occurring due to the existing control equipment.

In 1999, the electric utility industry nationwide participated in an extensive fuel and emissions testing program referred to as the Information Collection Request (ICR) required by the USEPA. The goal of the program was to investigate the relationship of mercury emissions to fuel characteristics, boiler types, and air pollution equipment. The program was conducted in two main phases. The first phase required samples to be periodically collected and tested for all solid fuels (coal, coke, tires, etc.) that were delivered during the entire year of 1999 for units over 25 MW (megawatts). This yielded a database of approximately 40,000 fuel samples specifying type of fuel, mercury content, fuel characteristics, and the origin of coal by mine location and/or seam.

In the second phase, 84 electric units were selected for testing stack emissions of mercury. The units were selected to represent a profile of boilers, fuel, and control equipment configurations found in the utility sector. The testing consisted of measuring mercury concentrations in the fuel and flue gas both before and after the existing pollution control equipment. Units tested in Wisconsin included Alliant Energy – Columbia and Nelson Dewey; Wisconsin Electric – Pleasant Prairie and Port Washington; XCEL Energy – Bayfront.

Analysis of the second phase data indicates mercury removal is primarily a function of the fuel chlorine content and particulate control equipment (electrostatic precipitator, fabric filter, wet scrubber, etc.). The chlorine was found to be a primary agent in oxidizing the mercury to a charged form that readily attaches to a particulate. The mercury / particulate is then removed in the particulate control equipment (fabric filter, electrostatic precipitator, etc.). In general, an increased amount of chlorine results in a higher percentage of oxidized mercury and therefore higher mercury removal. Since oxidized mercury is also soluble in water, it is also removed by wet scrubber systems used for sulfur dioxide control. Other secondary factors that influenced mercury removal include fuel properties such as sulfur, calcium, and moisture content, the flue gas temperature prior to control equipment, and the mixing or contact time between the mercury and flue gas particulate.

For this assessment mercury emission control achieved by an individual unit is best determined by a specific stack test or from information derived from a test on a similar unit. This provides a better estimate of mercury control and efficiency than has been available in the past. However, few of the major utility units have performed stack tests to determine control efficiency of the existing equipment. Also, fuel properties and particulate control equipment can significantly affect any one units mercury control efficiency. The estimates for the existing control efficiency will not be conclusive until stack testing is performed for all units.

In this assessment specific stack test information is taken from those tests performed for the ICR phase II effort **(1)** or from other stack test data available to the Department. For the majority of units that do not have stack test data the control efficiency is taken from the EPRI analysis of ICR data and their estimate of mercury emissions for each coal-fired boiler in the United States **(2)**. Units smaller than 25 MW were not addressed by EPRI, however estimates were derived from their analysis. Units smaller than 25 MW included in this assessment are Dairyland Power Cooperative - Alma 1, 2, and 3, and WE Energies - County Plant 1, 2, and 3.

The mercury content of the fuel is derived from the EPRI analysis of the 1999 ICR fuel data specific for each unit **(2)**. Since the ICR fuel testing did not include units less than 25 MW the average characteristics determined by the ICR data for each fuel type was applied to these units. The fuel consumption data used in this assessment is derived from the USEPA's Acid Rain program database for units greater than 25 MW **(3)**. Fuel consumption data from the Department's Air Emission Inventory is used for the units smaller than 25 MW **(4)**.

<u>Characterization of Major Utility Coal-Fired Boilers</u>

Table 1- Major Utility Generation Units and Utilization, includes all units that were coal-fired boilers from 1997 to 2001. A total of 42 units at 14 different facilities were firing coal during that period (see appendices - *Table A1- Major Utility Units Firing Coal in 1997-2001, Fuel Consumption, Utilization, and Electric Generation* for a detailed listing of fuel consumption, capacity factors and electrical generation for individual units). Note that this assessment does not include mercury emissions from combustion turbines that are primarily fired by natural gas.

Table 1. Major Utility Generation Units and Utilization (1997 – 2001)

Major Utility	No. of Facilities	No. of Units	Generation Capacity			Percent of	
			Total	Units >	Units <	Units >	Units <
AE	4	9	2,143	1,733	410	81%	19%
DPC	3	7	957	750	207	78%	22%
WE	5	17	2,851	2,263	588	79%	21%
WPSC	2	9	892	337	555	38%	62%
Total	14	42	6,843	5,083	1,760	74%	26%

Major Utility Mercury Emissions and Mercury Control Efficiency for 1997 - 2001

The estimate of the average mercury emission control and total mercury emissions at major utilities for the period 1997 through 2001 is included in *Table 2 - Estimate of Mercury Control Efficiency and Emissions*. On average, the four major utilities emitted approximately 2,400 pounds of mercury per year and achieved a 13% mercury control efficiency and during this period. The equipment configuration and control efficiency for each unit in the analyses of mercury control and emissions (1997 – 2001) is detailed in the appendix (see *Table A2 – Estimated Mercury Control and Average Emissions for 1997 through 2001)*.

Table 2. Estimate of Mercury Control Efficiency and Emissions That Occurred in 1997 through 2001 (3 year averages)

Major	Existing Control			Mercury Emissions			
	1997-1999	1998-2000	1999-2001	1997-1999	1998-2000	1999-2001	Analysis
AE	11%	11%	10%	687	671	653	687
DPC	23%	22%	22%	188	192	192	192
WE	12%	12%	12%	1,305	1,297	1,299	1,299
WPSC	16%	16%	16%	235	237	236	236
Average/Total	**13%**	**13%**	**13%**	**2,422**	**2,405**	**2,387**	**2,415**

Note: Shaded area denotes fuel consumption case assumed for each utility in the analysis.

Determination of Growth in Fuel Consumption

For this assessment the highest consecutive three-year average fuel consumption over a five-year period (1997-2001) is the basis for determining the amount of mercury each major utility is capable of emitting. For Dairyland Power Cooperative (DPC), WE Energies (WE) and Wisconsin Public Service Corporation (WPSC) this is the 1999 to 2001 three-year average. For Alliant Energy, 1997 to 1999 is the highest three-year average. As a result of this evaluation, no growth in fuel consumption is assumed to occur from existing coal-fired units at the major utilities.

Table 3 – Percent Fuel Consumption of Maximum Potential, indicates that overall consumption declined 1.2% based on the three-year averages of unit capacity utilization from 1997 through 2001 (the most recent years of available fuel consumption certified data). Three major utilities, DPC, WPSC and WE had slight increases, from 0.3 to 1.1%. Alliant Energy had a large decline of 5.1% in consumption, primarily due to less utilization of units under 200 MW.

Little or no growth is indicated by the analysis of fuel consumption over the historic five-year period. It is normal for fluctuations to occur on a year-to-year basis from variations in weather and other factors. Three-year averaging is used to minimize variance due to these factors. Selecting the highest three-year average in the analysis further mitigates the impact that a year of low fuel consumption would have in determining normal consumption.

Table 3. Percent Fuel Consumption of Maximum Potential (1997 – 2001)

	97-99	98-00	99--01	% Change 199' to 2001
Units > 200				
AE	77%	77%	76%	-1.4%
DPC	74%	74%	75%	1.7%
WE	87%	87%	88%	0.5%
WPSC	87%	86%	85%	-2.2%
Total	82%	82%	82%	-0.2%
Units < 200				
AE	48%	42%	37%	-28.9%
DPC	45%	48%	44%	-3.8%
WE	47%	48%	47%	-1.1%
WPSC	77%	79%	79%	3.5%
Total	55%	55%	52%	-5.1%
All Units				
AE	70%	69%	67%	-5.1%
DPC	67%	68%	68%	0.9%
WE	77%	77%	77%	0.3%
WPSC	81%	82%	82%	1.1%
Total	74%	74%	73%	-1.2%

Notes:
-Shaded area indicates high fuel consumption years for each major utility.
-Capacity utilization based on federal acid rain program fuel consumption data and Wisconsin DNR air emissions inventory.

Units over 200 MW (megawatts) operated by WPSC and WE have high consumption levels 85% and 88%, respectively, from their maximum potential. Typically, it is expected that the highest utilization that these units could achieve is no more than 90% to 95% considering maintenance requirements and system management requirements. As units age, this potential capacity is not expected to increase unless there are major equipment upgrades or significant operational changes. Therefore these units are considered to be near their maximum capacity utilization. For DPC and AE, their units over 200 MW had fuel consumption levels of 75% and 77%, respectively, indicative of the potential for growth. However, their fuel consumption data for the period 1997-2001 does not indicate a trend toward growth.

Units below 200 MW do not show a trend toward increased utilization. The majority of these units are nearing retirement and their operation levels have reached their peak (see appendices *Table A1 Major Utility Units Firing Coal in 1997-2001, Fuel Consumption, Utilization, and Electric Generation*). It is expected that new capacity or re-powering will replace aging small unit utilization and account for future growth. This is demonstrated by WE's re-powering of their Port Washington Generating Station and the conversion of AE's Rock River Generating Station to natural gas. In addition, three of the major utilities are seeking approval or developing plans for adding significant new coal-fired capacity to address growth.

Major Utility Mercury Emissions and Mercury Control Efficiency for 2008

Table 4 - Estimate of Mercury Control Efficiency and Emissions by 2008, summarizes the anticipated mercury control efficiency and mercury emissions in 2008 for each major utility. *Table A3 – Estimated Mercury Control and Emissions for 2008*, in the appendices, provides the detailed information used to arrive at these averages. These estimates establish the foundation for determining the incremental improvement in overall mercury control efficiency that will be achieved from the installation of the surrogate mercury control technology defined in Section III.

Based on this analysis major utilities are expected to achieve an average mercury control efficiency of 19% and emit 2,259 pounds of mercury per year in 2008. Anticipated mercury control efficiency varied from 15% to 37% and increased for each major utility over current levels (see Table 2) with the exception of Dairyland Power Cooperative. These increases are the result of a recently installed fabric filter at Wisconsin Public Service Corporation – Weston 3 unit, repowering of the WE Energies – Port Washington Station, and conversion of Alliant Energy – Rock River Station to natural gas.

Table 4. Estimate of Mercury Control Efficiency and Emissions by 2008

Major	**Anticipated Efficiency**	**Mercury (lbs/yr)**
AE	15%	654
DPC	22%	192
WE	17%	1,227
WPSC	37%	178
Average/Total	**19%**	**2,259**

III. Surrogate Mercury Control Technology

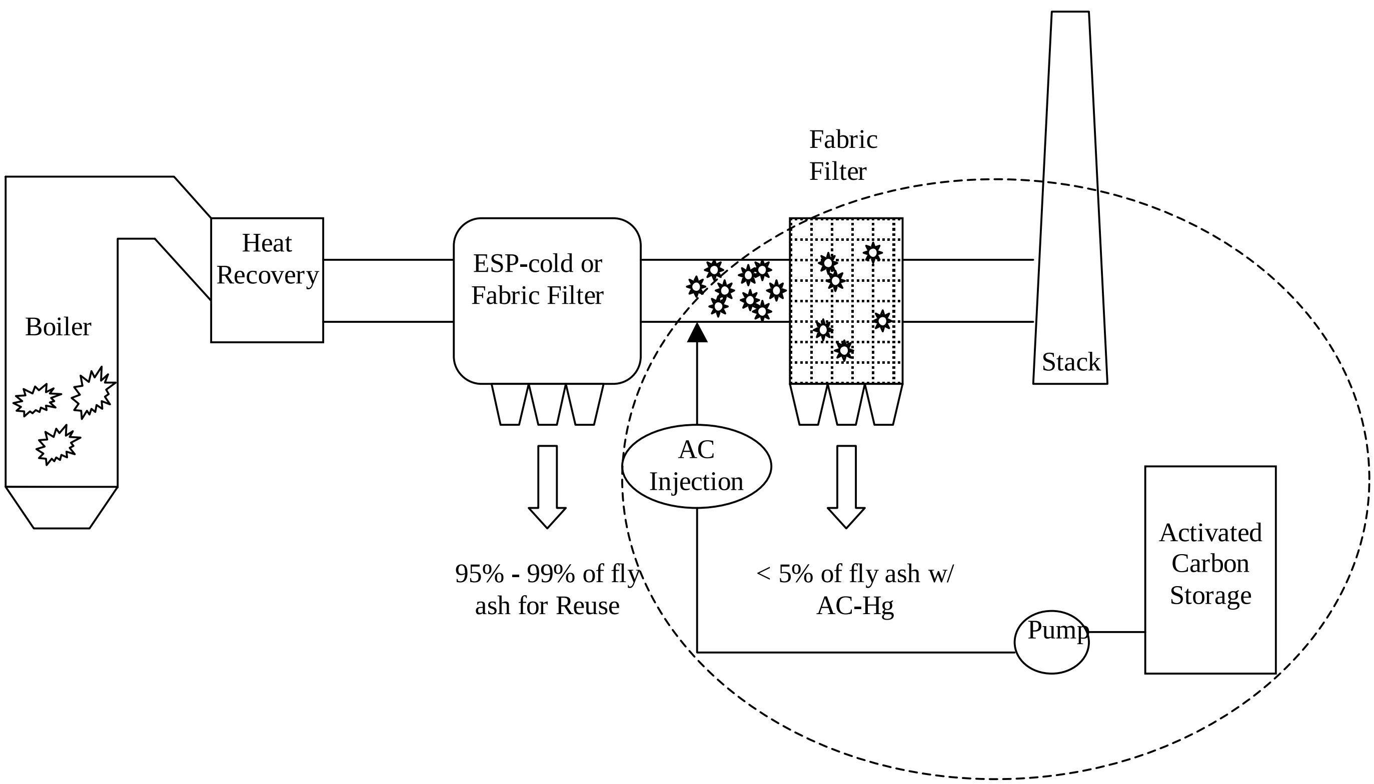
This section includes a determination of the level of mercury emission control that the surrogate technology can achieve. Two configurations of the surrogate technology are considered. One configuration, activated carbon injection with dedicated polishing fabric filter system (AC/FF), is deemed suitable for installation on units where a long-term capital investment is appropriate. These are generally newer larger units (greater than 200 MW) that have significant use. The second configuration is activated carbon injection (AC) alone upstream of the existing particulate control equipment. The second configuration is more appropriate for older smaller units that are declining in use. Also, provided is a description of the two configurations and rationale for selecting which configuration each of the 42 major utility coal-fired boilers should receive.

Activated Carbon Injection / Polishing Fabric Filter System Configuration (AC/FF)

This configuration controls mercury through the injection of activated carbon into the flue gas stream after the existing particulate control equipment but prior to a newly installed polishing fabric filter as shown in schematic 1. The injected carbon adsorbs both the ionic and elemental mercury and forms a mercury / activated carbon particulate that is captured in the polishing fabric filter. This configuration requires the installation of activated carbon storage, injection equipment, and a polishing fabric filter system.

This configuration minimizes the impact on the reuse of fly ash. According to EPRI, 95% of more of the original fly ash is collected in the existing particulate control equipment as depicted in schematic 1 and therefore retains its reuse potential **(5)**. The remaining 5% of fly ash becomes contaminated with activated carbon and is collected downstream in the polishing fabric filter along with the captured mercury.

A 90% mercury control efficiency measured from the fuel input to the final exhaust gas is assumed for all units regardless of existing pollution control equipment or fuel type. This level of control is achievable based on test results for fabric filter mercury removal, with and without activated carbon injection. According to ICR data, fabric filters demonstrate control efficiencies from 48% to 86% for units firing sub-bituminous coal and 35% to 99% for units firing bituminous coal **(1)**. The high removal rates are attributed to the fabric filters producing a high level of contact between the fly ash and mercury as the flue gas passes through the filter cake. The addition of activated carbon prior to the fabric filter enhances this process with a compound that readily absorbs both ionic and elemental forms of mercury.



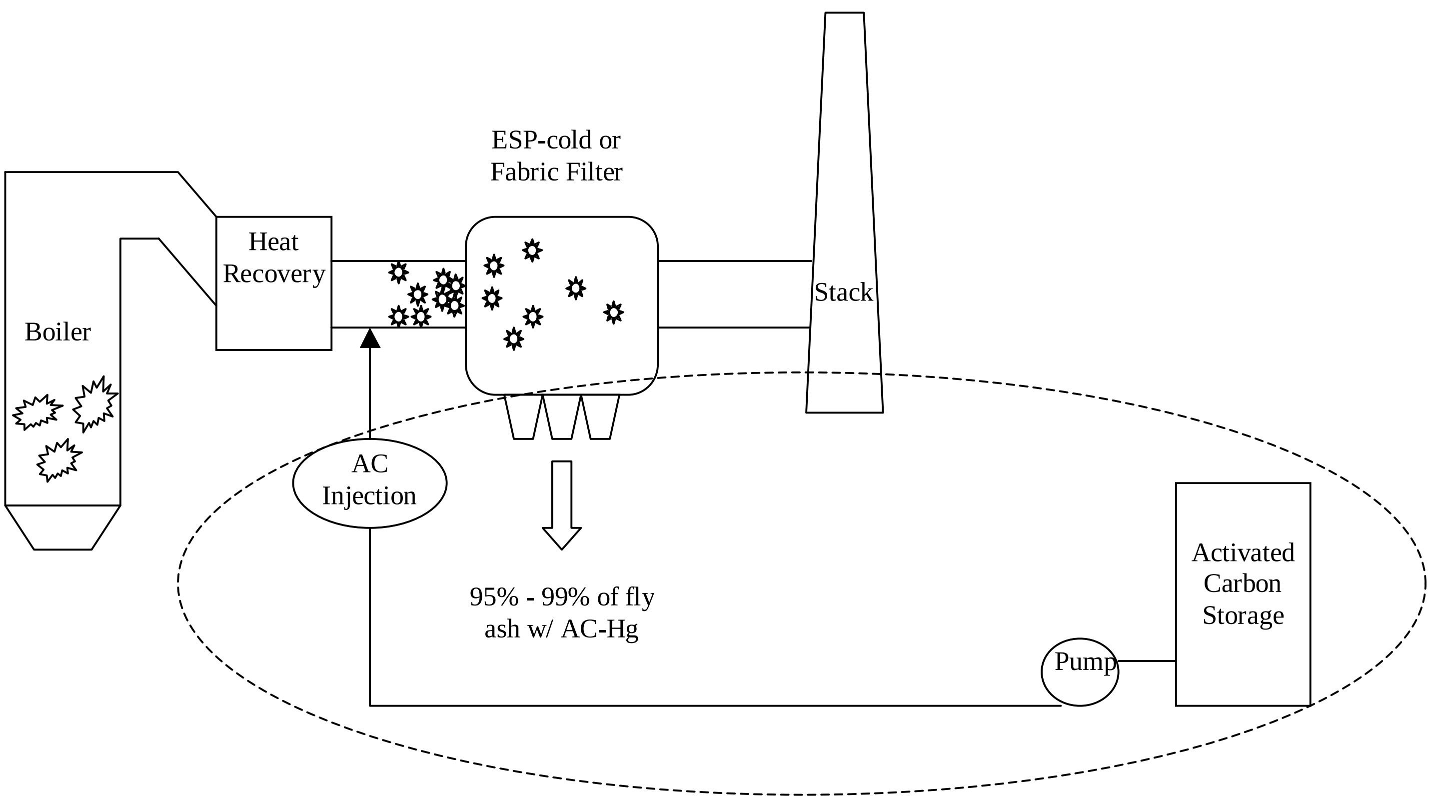
Schematic 1 - Activated Carbon Injection / Polishing Fabric Filter System (AC/FF)

The United States Department of Energy (USDOE), USEPA, EPRI and participating utilities have conducted pilot testing and one full-scale test of activated carbon injection prior to an existing fabric filter. The pilot scale test results, as compiled by EPRI **(2)** demonstrated control efficiencies ranging from 70% to greater than 90%. A control efficiency of 80% was maintained over an extended period without any evident adverse plant operation impacts at an activated carbon injection rate of 2 pounds per million cubic feet per minute of exhaust gas.

Based on this testing EPRI has stated that the 90% control efficiency is achievable with this configuration however, additional testing at 2 to 4 sites involving different coals is necessary to perfect design and operation to achieve this level **(5)**. This could be completed over a three-year period. This pilot testing has also demonstrated that given proper contact time the carbon adsorbs both ionic and elemental mercury and therefore its use is not limited by fuel type (sub-bituminous vs. bituminous). These results indicate that proper design and optimization would achieve the expected 90% or greater control efficiency for this configuration across all fuel types.

Activated Carbon Injection Configuration (AC)

In this configuration, activated carbon is injected upstream of an existing particulate control device where the mercury / activated carbon particulate is removed (schematic 2). This configuration can be applied to units with an existing cold-side electrostatic precipitator or a fabric filter. In front of the existing particulate control equipment activated carbon enters into the flue gas stream adsorbing both ionic and elemental mercury.



Schematic 2 - Activated Carbon Injection (AC)

This configuration is appropriate for smaller less utilized generation units. The majority of units less than 200 MW at the major utilities are in this category (see *Table 1- Major Utility Generation Units and Utilization*). In addition, these units do not have a remaining life expectancy beyond that of a newly installed fabric filter and thus may be poor candidates for a large capital investment. This configuration only requires installation of activated carbon storage and injection equipment. It is significantly less capital and equipment intensive than the AC/FF configuration.

Although the fly ash generated at these units will now contain activated carbon and mercury, no impact to fly ash reuse is assumed in the cost analysis. These units, in general, produce a lower quality fly ash that is typically disposed of in a landfill. In some cases it has been used for fill or re-burned to capture lost fuel value, but these options are not consistently available. For a system with an existing electrostatic precipitator the injection of activated carbon is expected to achieve 60% mercury control efficiency. Full-scale testing at WE's Pleasant Prairie Power Plant demonstrated 60% mercury control efficiency at an activated carbon injection rate of 5 pounds per million actual cubic feet per minute with no noticeable plant operation impacts **(5)**.

In their analysis, EPRI believes that the AC configuration requires an additional 6 months to 2 years of testing to determine AC effectiveness on a range of fuel types and particulate control systems **(5)**. It should also be noted that the electrostatic precipitator at WE - Pleasant Prairie has been converted from a hot-side to a cold-side unit, thus physically, the precipitator is oversized which creates more retention time and contact surface than a conventional cold-side unit configuration.

With an existing fabric filter, this configuration is assumed to achieve 80% control efficiency at an activated carbon injection rate of 2 pounds per million actual cubic feet per minute. This control level would apply to WE's four units at their Valley Power Plant that are equipped with existing fabric filter systems.

<u>Application of the Surrogate Control Technology Configurations to Specific Units</u>

The AC/FF configuration is applied to units that comprise the core generation capacity at each major utility. For Dairyland Power Cooperative (DPC), WE Energies (WE) and Alliant Energy (AE) this includes all units greater than 200 MW. For Wisconsin Public Service Corporation (WPSC) this includes Weston 1, with a capacity greater than 200 MW, and Weston 2 and 3 and Pulliam 7 and 8, which are units less than 200 MW. WPSC's relies on small units to provide 62% of capacity. This is significantly greater than any of the other major utilities where small units, on average, provide only 20% of generation capacity (*see Table 1- Major Utility Generation Units and Utilization*). With the inclusion of the small units at WPSC approximately 80% of the generation capacity of each major utility would be subject to the installation of the AC/FF configuration.

The AC configuration is applied to smaller less utilized units that are expected to cease operation within the next 15 years (Refer to *Table AI – Major Utility Units Firing Coal in 1997-2001* for unit age and capacity information for all units). *Table 5 – Application of Surrogate Control Technology Configurations*, depicts the number of units that would install configuration, AC/FF or AC, and the percent of generating capacity that each configuration would affect. The configuration that each unit is assigned can be found in the Appendices (see *Table A4 – Percent Mercury Control by Utility*).

Table 5. Application of Surrogate Control Technology Configurations

Major Utility	Threshold	AC/FF			AC		
		No. of Units	% of Capacity	% of Generation	No. of	% of Capacity	% of Generation
AE	200 MW	4	81%	85%	5	19%	15%
DPC		2	78%	86%	5	22%	14%
WE		6	79%	88%	11	21%	12%
WPSC	Weston 1,2,3 and Pulliam 7,8	5	81%	83%	4	19%	17%

IV. Surrogate Technology Installation Schedule

The surrogate technology installation schedule includes three distinct periods - technology optimization, utility planning, and design and equipment installation. In order to achieve significant mercury emission reductions a schedule that accommodates each of these periods is essential. The installation schedule established considers the benefits of allowing additional time for mercury control technology development to occur before commencing system-wide planning and design. The feasibility of mercury control must also account for the time necessary to implement significant installation of equipment across multiple units while still meeting electricity demand.

Table 6 - Assumptions and Parameters for Surrogate Technology Installation Schedule provides the time in years required for each period for each configuration, AC and AC/FF. Common to both configurations is an initial three-year period for technology optimization recommended by EPRI **(5)**. By the third year of this period it is assumed the utilities will have sufficient information to begin a two-year period of specifying system-wide technology choices and initial planning for all unit installations.

Table 6 Assumptions and Parameters for Surrogate Technology Installation Schedule

AC/FF System	Requirement
- Technology optimization	3 years
- Utility planning	2 years
- Design and installation	3 years
- Period between 1st and 2nd installati	2 years
- After 2nd installation a new unit begins operation each year	Annual

AC System	Requirement
- Technology optimization	3 years
- Utility planning	2 years
- Design and installation	1 year
- Periodic installations	Annual

The remaining periods are specific to each technology configuration. For AC/FF, this includes a three-year design and installation period for the initial installation followed by a two-year period for the second unit to begin operation at a major utility. Design of the second unit is assumed to begin in the last year of installing the initial unit. It is then assumed that design and installation can be undertaken sequentially such that one new AC/FF system will begin operating each year after the second unit installation.

Table 7. Schedule for Installing Surrogate Technology

Calendar Year	Schedule Year	AC/FF	AC
2003 - 2006	0 -3	--------------------------Full-scale testing and optimization--------------------------------	
2005 - 2007	2 to 4	--------------------------Initial utility system-wide planning--------------------------------	
2007 - 2009	4 to 6	1st unit design and installation	
2009 - 2011	6 to 8	2nd unit design and installation	
2010	7	1st unit operating	1st unit design and installation
2011	8		1st unit operating /2nd unit design and installation
2012	9	2nd unit operating	2nd unit operating
2013 - 2015	10 to 12	One new unit operating each year	One new unit operating each year

Following these assumptions results in the schedule shown *in Table 7 - Schedule for Installing Surrogate Technology*. Note that the schedule is assumed to commence beginning January 1, 2003. According to this schedule initial mercury emission reductions from the installation of surrogate technology begin in

2010. By 2015, the final mercury reduction level is achieved from the application of the surrogate technology.

The initial AC/FF system begins operation in the 7th year or in 2010. By 2015, the 12th year of the schedule, all AC/FF systems are installed. See *Table A4 – Percent Mercury Control by Utility* in the appendices for the assumed sequence of installations by unit for each major utility. It is important to note that Dairyland Power Cooperative will only need two AC/FF systems. Alliant Energy will need four AC/FF systems and these installations are complete by the 11th year or 2014. WE Energies and Wisconsin Public Service Corporation will have their last AC/FF systems operating in the 12th year or 2015.

The schedule of installation also targets the higher capacity unit first within each major utility system. AC system installation does not commence until after the initial AC/FF system for each utility is operating. This is intended to allow the maximum amount of capacity to be available while each utility is installing the AC/FF system on their largest capacity unit and to minimize any potential reliability issues.

The AC systems are not equipment intensive and can be designed and installed on annual basis. Starting in the 8th year, or 2011,each major utility begins operation of a new AC system. Only WE Energies will have these installations occurring through 2014. The sequence of AC system installations by unit for each major utility is outlined in *Table A4 – Percent Mercury Control by Utility*.

The installation schedule minimizes impacts to electric reliability. An important additional consideration is the effect on reliability caused by overlapping plant outages at several major utilities for the purpose of equipment installation. This type of reliability impact was evaluated by the Wisconsin Public Service Commission (PSC) for a potential statewide installation of nitrogen oxide (NOx) pollution control equipment. The PSC concluded that outages due to installing major equipment would not have adverse impact on electric reliability. Further, the PSC recommended that utilities submit a joint report to address coordinating installations and outages **(6)**.

In comparison, the mercury surrogate control installation schedule addresses approximately the same number of units however, the installation schedule is longer than the proposed NOx program. For the NOx program the utilities projected installing selective catalytic reduction (SCR) equipment on every major unit within a three year period. The mercury schedule assumes major equipment construction and installation over a potential eight to ten year period. The installation time is two to three years for either a SCR or a AC/FF. Therefore, electric reliability should not be an issue for the proposed surrogate mercury technology installation schedule.

V. Major Utility Mercury Control Achieved

In this section the cumulative mercury control achieved by the installation of the surrogate technology is determined. The starting point for this determination is the expected level of mercury control that is being achieved in 2008 (see Section II). The mercury control resulting from existing pollution control equipment is expected to range from 15% to 37% among the four major utilities with an overall average of 19%. *Table 8 - Percent Mercury Control*, depicts the mercury control level achieved from installation of the surrogate control technology that follows the schedule presented in Section III. The calculation of the control levels in Table 8 assume that the 2008 control level determined for a unit is replaced by the surrogate technology control level according to the detailed installation schedule in *Table A4 – Percent Mercury Control by Utility* in the appendices.

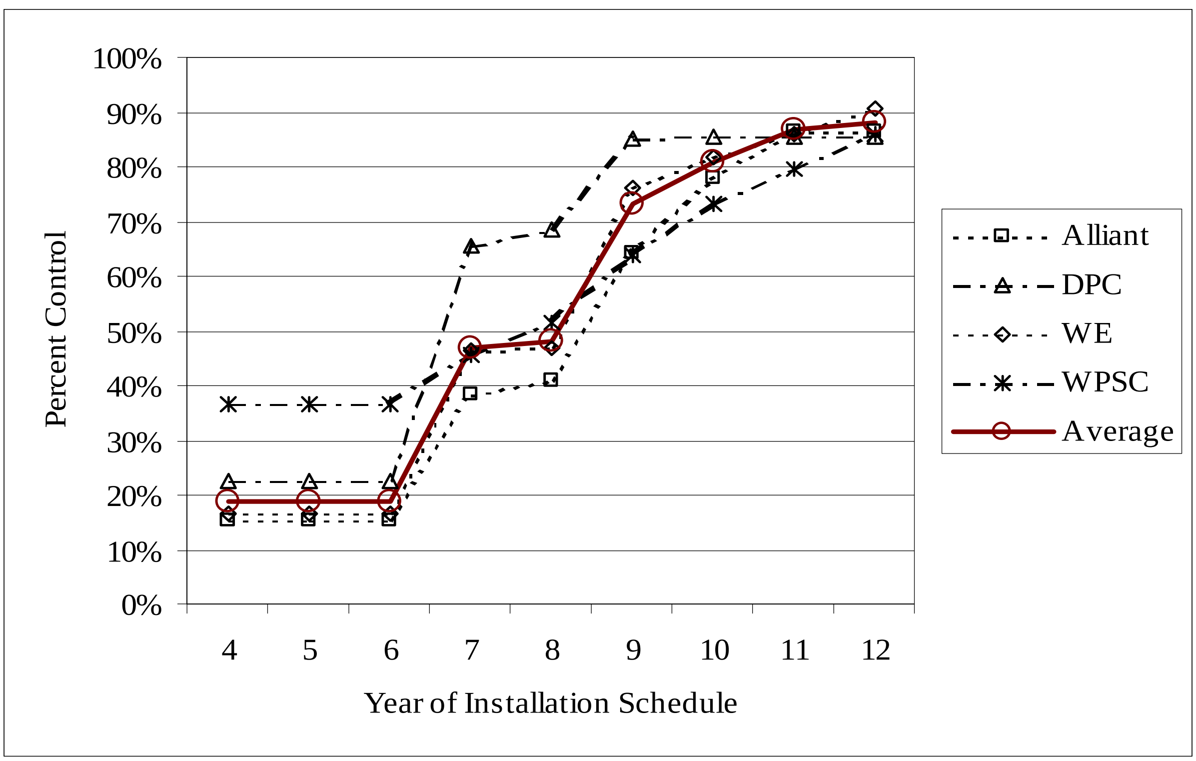
Table 8. Percent Mercury Control

	Existing Control	Existing + Surrogate Technology Control					
Major Utility	**6** 2009	**7** 2010	**8** 2011	**9** 2012	**10** 2013	**11** 2014	**12** 2015
AE	15%	38%	41%	64%	78%	86%	86%
DPC	23%	66%	69%	85%	86%	86%	86%
WE	17%	46%	47%	76%	82%	86%	91%
WPSC	37%	46%	52%	64%	73%	80%	86%
Average	19%	47%	48%	73%	81%	87%	88%

According to the proposed installation schedule, the largest uncontrolled unit of each major utility will have an AC/FF system in operation by the 7th year (2010). As shown in *Table 7 - Schedule for Installing Surrogate Technology*, this installation along with the existing control achieved on the remaining units results in an average 44% reduction of uncontrolled mercury emissions. The lowest reduction is 38% for Alliant Energy and the highest is 66% for Dairyland Power Cooperative.

Figure 1 - Percent Mercury Control from Existing and Surrogate Control Technology, depicts the improvement in mercury control that occurs as the surrogate control technology systems become operational. At the completion of the schedule, uncontrolled mercury emissions have been reduced by 88% from all coal-fired units operated by the major utilities during the period 1999 to 2001. In addition, each major utility has achieved at least an 86% mercury control level with the range from 86% to 91%.

Figure 1. Percent Mercury Control from Existing and Surrogate Control Technology



VI. Cost of Surrogate Control Technology

The installation schedule for surrogate control technology is outlined in *Table A4 – Percent Mercury Control by Utility* in the appendices. The estimated annual mercury control cost is the annualized cost of installing and operating the surrogate control technology that follows that installation schedule. Costs are determined for each unit based on the control parameters and additional requirements identified for each surrogate technology configuration in *Table 9 - Surrogate Control Technology Parameters*. The specific equipment cost and operation factors are listed in *Table 10 - Surrogate Control Technology Cost Analysis Factors*. These factors were obtained from the EPRI analysis of mercury control technology **(5)**, USEPA **(1)**, or consideration of other industry information **(7)**.

<u>Surrogate Control Technology Installation Parameters and Cost Factors</u>

The surrogate control technology is applied in two different configurations to all 42 units based on the distinctions summarized in *Table 9 - Surrogate Control Technology Parameters*. The configuration applied to high utilization units is activated carbon injection with a dedicated polishing fabric filter system (AC/FF). This configuration is assumed to achieve 90% control efficiency and to preserve the reuse of at least 95% of fly ash generated. The use of a dedicated fabric filter has the benefit of significantly reducing the amount of activated carbon required while still achieving high mercury control levels.

For smaller, less utilized, and older units the control configuration is activated carbon injection (AC) with an assumed mercury control efficiency determined by the existing particulate control equipment, 60% for an electrostatic precipitator or 80% for a fabric filter. The AC configuration achieves mercury control without a large capital investment in equipment that has a longer expected life than the unit.

Table 9. Surrogate Control Technology Parameters

Existing Equipment Configuration		Surrogate Control Parameters				Additional Requirements	
Category	**Existing Equipment**	**Technology**	**AC Injection Rate (lbs/mmacf)**	**Control Efficiency**	**Impact to Flyash Reuse**	**Expected Cost**	**High Cost**
Low utilization units and remaining lifetime < 15 years	ESP-coldside	AC	5	60%	none		install extra ESP field
	ESP-hotside	AC	5	60%	none	ESP converted from hotside to coldside	install extra ESP field
	Fabric Filter	AC	2	80%	none		
High utilization units with remaining lifetime > 15 years	All Units	AC/FF	2	90%	95% Flyash Reused	- 5% flyash landfilled - Either oversized fabric filter or reduced filter life	- 5% flyash disposed as hazadous waste - Both oversized fabric filter and reduced filter life

In applying the surrogate control equipment an “Expected Cost” and “High Cost” effort is identified that reflects a potential range in costs.

For example, in recognition of the electrostatic precipitator condition for the pilot test of AC at WE Energies Pleasant Prairie, installation of an extra collection field for cold-side electrostatic precipitators is considered in the high cost effort. For hot-side precipitators, affecting two units at Alliant Energy Nelson Dewey, the expected cost effort requires conversion to cold-side precipitators and the high cost effort adds an extra collection field to the conversion.

Lost revenue from fly ash are evaluated under two disposal situations, disposal in a sanitary landfill, expected cost, or disposal as a hazardous waste, high cost. Note that the Department is not anticipating that fly ash from an AC/FF system will need to be treated as a hazardous waste. Its designation here is in response to a comment on possible costs for this configuration that should be evaluated. To account for increased particulate loading from injecting activated carbon into the exhaust gas, the analysis for the expected case considers either a shortening of filter life or enlarging the size of the polishing fabric filter. For a particular application the most cost-effective approach was selected. The high cost effort considers both reduced filter life and an oversized fabric filter design.

Table 10. Surrogate Control Technology Cost Analysis Factors

Parameter	Cost Factor	Reference
Economic Analysis Factor		
Fixed charge rate	15%	5
Utility investment return rate	8%	5
Equipment life	15 years	5
Activated Carbon Injection System		
Injection and storage equipment	2$/KW	5
Annual operation and maintenance	0.4$/KW	5
Activated carbon	0.5$/lb	5
Existing Equipment Modifications		
Convert hot-side ESP to cold-side	50$/KW	5
Install extra ESP collection field	12$/KW	5
		5
Fabric Filter		
Fabric filter system	40$/KW	5
Annual operation and maintenance	2 M$/yr	5
Factor for oversizing fabric filter	10$/KW	5
Annual cost for reduced fabric filter life	0.6M$/yr	5
Flyash Impacts		
Lost revenue for cement reuse	10$/ton	1, 5, 7
Landfill disposal cost	30$/ton	1, 5, 7
Hazardous waste disposal	200$/ton	1, 5

The analysis does not include any cost for electric purchases by a major utility during the installation of surrogate control technology equipment. The installation schedule is assumed to minimize this potential impact.

The initial capital cost of equipment and installation is annualized using a fixed charge rate of 15%, recommended by EPRI for utility pollution control equipment with an expected 15 year equipment life and an 8% return on investment. Beyond 15 years, the only costs are for material consumption and operation and maintenance costs. Annual costs will increase if either the equipment life is shortened or the rate of return increases. *Table A5 – Mercury Control Costs for Application of Surrogate Control Technology*, details how annual cost accrues throughout the installation schedule for both the expected and high cost cases outlined in *Table 9*.

<u>Cost Summary for all Major Utilities</u>

The total annual expected and high costs for each utility are summarized in *Table 11 - Estimate of Surrogate Technology Mercury Control Cost (Million $ / Year)*. The analysis assumes the annual cost of a unit is first incurred in the year it begins operation. The ongoing annual cost peaks in the 12th year of the schedule when all surrogate control installations are operating. This is the final annual cost that continues through the life of the surrogate technology equipment. The initial annual cost for all major utilities starting in 2010 (7th year) is 28 to 33 million dollars for the expected and high cost cases, respectively. This cost represents each utility operating one AC/FF on their largest mercury-emitting unit. The final annual cost for all units operating in 2015 (12th year) is 87 to 104 million dollars for the expected and high cost cases, respectively.

Table 11. Estimate of Surrogate Technology Mercury Control Cost (Million $ / Year)

Major Utility	Schedule Year						Outgoing Years	
	2010	2011	2012	2013	2014	2015	2030	2035
	7	8	9	10	11	12	20	25
Expected Cost Scenario								
AE	8	8	16	22	26	26	26	<26
DPC	5	6	11	11	11	11	11	<11
WE	10	10	21	28	33	37	37	<37
WPSC	5	6	8	9	10	12	12	<12
Total	28	30	56	71	81	87	87	<87
High Cost Scenario								
AE	9	10	19	26	31	31	31	<31
DPC	6	7	14	14	14	14	14	<14
WE	11	12	24	33	38	44	44	<44
WPSC	6	7	10	12	14	16	16	<16
Total	33	35	66	84	96	104	104	<104

The annual cost is expected to remain constant from the 12th year through the expected life of the surrogate control equipment, 15 years. This ongoing cost is expressed under the "outgoing years" in Table 9 where the annual cost remains the same from the 12th to the 20th year. However, by the 25th year the annualized capital cost of many unit installations will be paid off and the total annual cost will begin to decrease. The increase in electricity rates from the installation of the surrogate control technology is normalized to the amount of electricity generated by all 42 coal-fired units (see appendices Table A1).

The resulting incremental cost in cents per kilowatt-hour is compiled in *Table 12 - Incremental Electricity Cost of Surrogate Control Technology (cents / kilowatt-hour)* for each utility. This shows the cost for the 47% mercury control achieved in 2010 (7th year) adds an electricity cost of 0.06 to 0.07 cents per kilowatt-hour (kWh). By 2015 (12th year) at 88% mercury control the average cost ranges from 0.19 to 0.23 cents per kWh.

Table 12. Incremental Electricity Cost of Surrogate Control Technology (cents / kilowatt-hour)

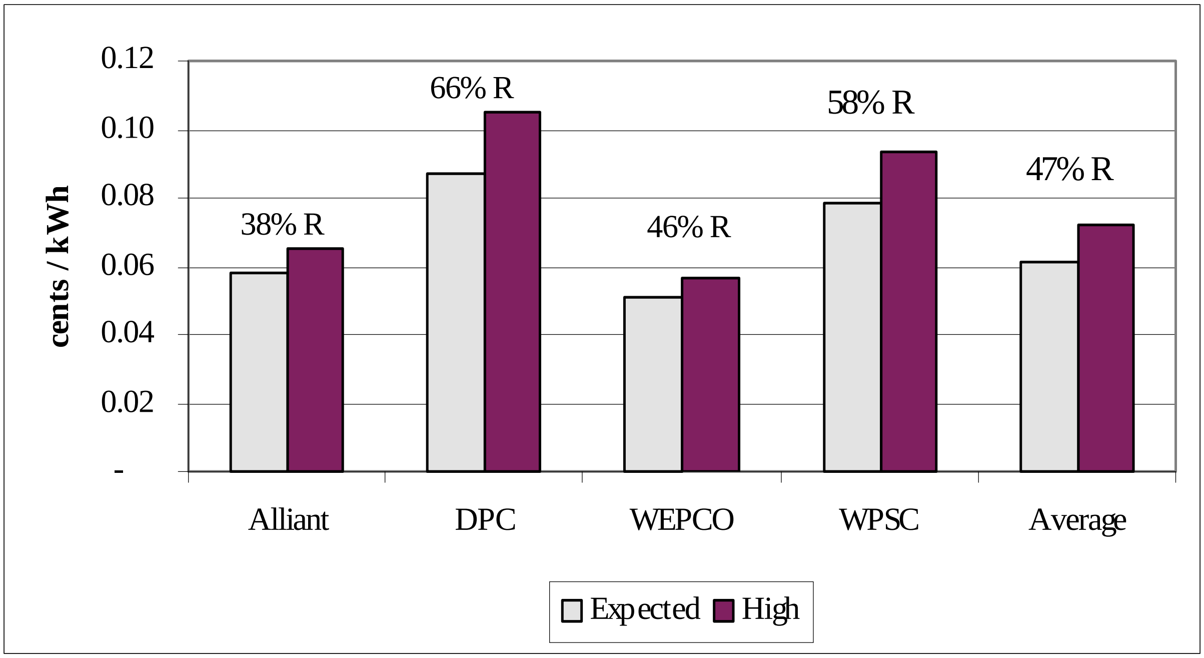
Major Utility	Schedule Year						Outgoing Years	
	2010	2011	2012	2013	2014	2015	2030	2035
	7	8	9	10	11	12	20	25
Expected Cost Scenario								
AE	0.06	0.06	0.12	0.16	0.19	0.19	0.19	<0.19
DPC	0.09	0.10	0.19	0.19	0.19	0.19	0.19	<0.19
WE	0.05	0.05	0.11	0.14	0.17	0.19	0.19	<0.19
WPSC	0.08	0.09	0.12	0.14	0.16	0.19	0.19	<0.19
Average	0.06	0.07	0.12	0.16	0.18	0.19	0.19	<0.19
High Cost Scenario								
AE	0.07	0.07	0.14	0.19	0.22	0.22	0.22	<0.22
DPC	0.10	0.12	0.24	0.24	0.24	0.24	0.24	<0.24
WE	0.06	0.06	0.12	0.17	0.19	0.22	0.22	<0.22
WPSC	0.09	0.11	0.16	0.19	0.22	0.25	0.25	<0.25
Average	0.07	0.08	0.15	0.18	0.21	0.23	0.23	<0.23

Individual Major Utility Costs

Figure 2 - Incremental Electricity Cost at the 47% Average Mercury Control Level for Surrogate Control Technology, illustrates the difference in incremental electricity cost between the major utilities in 2010. For the expected case the cost ranges from 0.05 cents/kWh for WE to 0.09 cents/kWh for Dairyland Power Cooperative. The higher cost for Dairyland Power Cooperative and Wisconsin Public Service Corporation is due to a larger portion of their system capacity being covered by the first installation as compared to Alliant Energy and WE Energies.

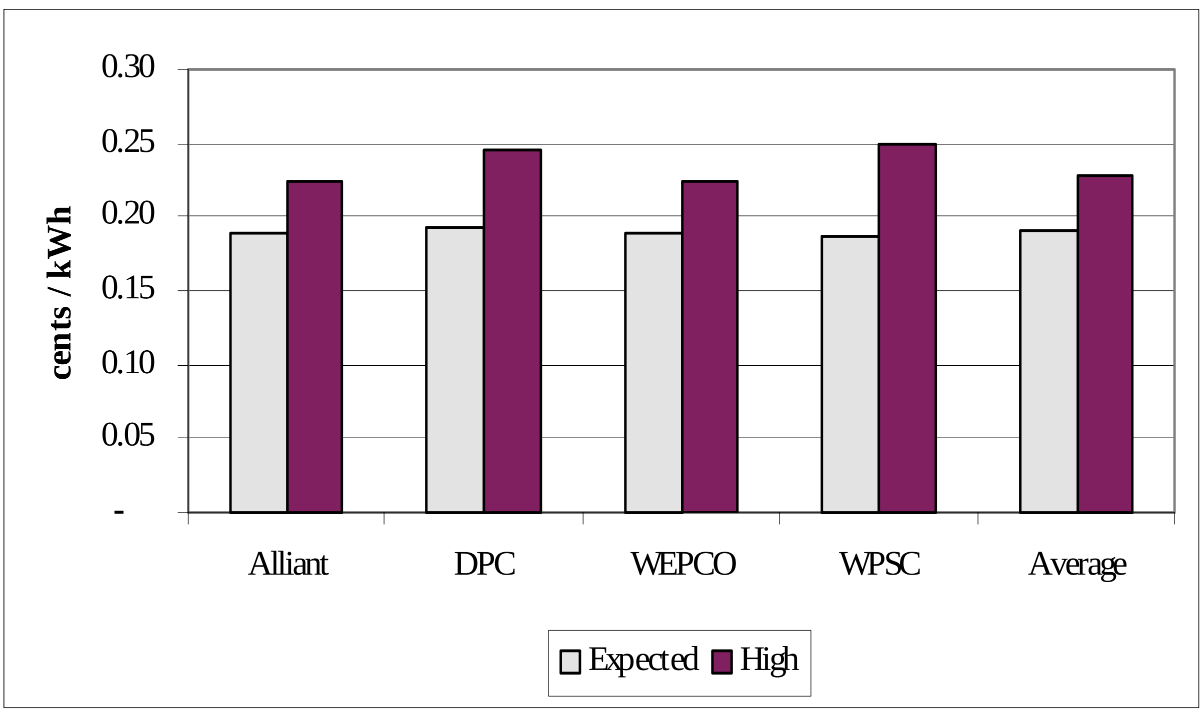
At the final control level of 88%, as illustrated in *Figure 3 - Incremental Electricity Cost at the 88% Average Mercury Control Level for Surrogate Control Technology*, the incremental cost is almost comparable among all major utilities. The cost for the expected case for all major utilities is 0.19 cents/kWh. The cost for the high case for all major utilities is 0.22 to 0.25 cents/kWh.

Figure 2. Incremental Electricity Cost at the 47% Average Mercury Control Level for Surrogate Control Technology.



R = the utility mercury removal or control level.

Figure 3. Incremental Electricity Cost at the 88% Average Mercury Control Level for Surrogate Control Technology.



Estimated Consumer Costs

The cost impact to the consumer or ratepayer is estimated by applying the incremental electricity cost to indices of electricity consumption. The estimated cost impacts to the residential, commercial, and industrial consumer are compiled in *Table 13 - Estimate of Consumer Incremental Cost from Surrogate Control Technology (dollars / year)*.

The cost to the residential consumer is based on the average household consuming 770 kWh per month or 9,240 kWh per year **(8)**. The calculated initial residential household cost beginning in 2010 as shown in *Figure 4 - Estimate of Annual Household Cost vs. Mercury Control for Surrogate Control Technology*, may range from 6 to 7 dollars per year. The final cost in 2015 is estimated to range from 18 to 21 dollars per year. The annual household cost versus mercury control achieved through the installation schedule is illustrated in *Figure 4*.

Table 13. Estimate of Consumer Incremental Cost from Surrogate Control Technology (dollars / year)

Sector	Unit	Indices	Initial Cost ($/year)		Final Cost ($/year)	
			Expected	High	Expected	High
Residential	Household	9,240 kWh/year (1)	6	7	18	21
Commercial	Customer	60,513 kWh/year (1)	37	44	116	138
Industrial	Net Proceeds	0.46 kWh/$1000 (2)	0.28	0.33	0.88	1.05
	Value Shipped Product	0.21 kWh/$1000 (3)	0.13	0.16	0.41	0.49

1) Wisconsin Energy Statistics 2002, Wisconsin Energy Bureau

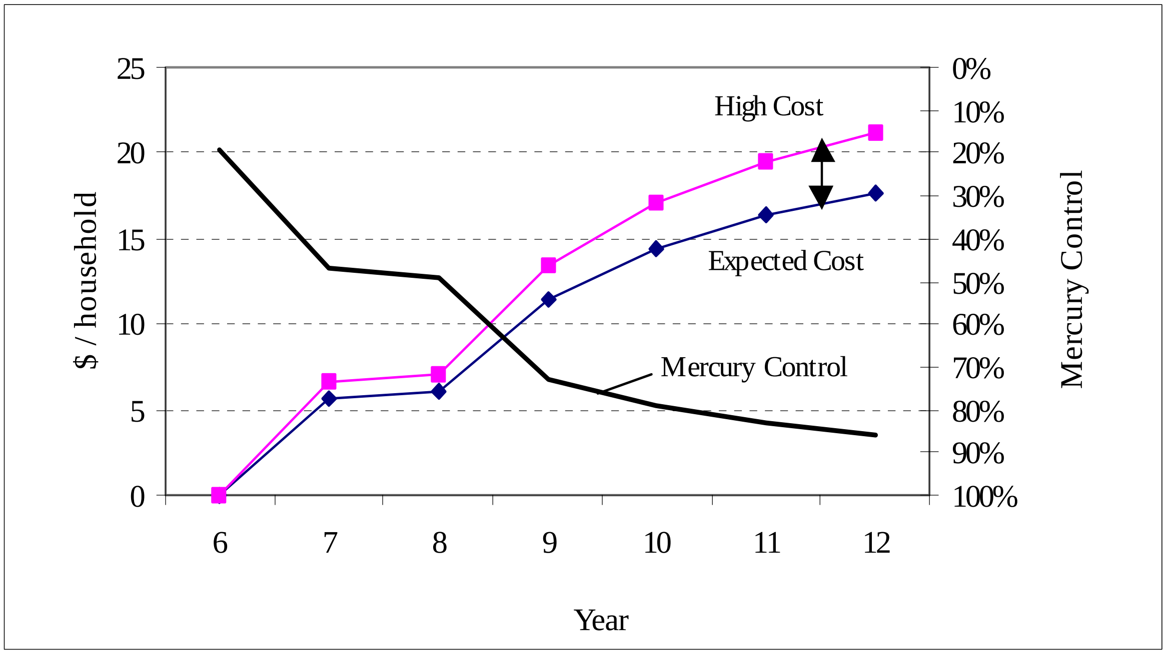
2) Indices calculated as the total industrial electric consumption of 23,523 per Wisconsin Energy Statistics 2002, divided by the total manufacturing value added of 50,998,900,000 dollars in 1996 per Wisconsin Economic Profile, Department of commerce.

3) Indices calculated as the total industrial electric consumption of 23,523 per Wisconsin Energy Statistics 2002, divided by the total manufacturing value added of 109,593,100,000 dollars in 1996 per Wisconsin Economic Profile, Department of commerce.

According to the Wisconsin Energy Bureau the average commercial customer purchases 60,513 kWh per year **(8)**. On this basis the initial cost in 2010 may range from 37 to 44 dollars per year. At the final control level in 2015 the cost is 116 to 138 dollars per year.

In the industrial sector electric consumption varies considerably between customers making it difficult to determine a meaningful average cost. However, one means of expressing the added cost is in relation to the value of net proceeds and of shipped product. Indices were developed based on the total industrial electricity consumption of 23,523 megawatt-hours for 2002 **(9)** and dividing this by either the net proceeds of 50,998,900,000 dollars or value shipped of 109,593,100,000 dollars determined in for the 1996 business year. **(9)**. This results in the indices of 0.46 kWh electricity consumed per $1000 of net proceeds and 0.21 kWh of electricity consumed per $1000 of the value of shipped products. The cost is then determined by multiplying these indices by the calculated incremental electricity cost due to mercury control.

Figure 4. Estimate of Annual Household Cost vs. Mercury Control Achieved by the Surrogate Control Technology



The Industrial estimated cost impact using the net proceeds basis is 0.28 to 0.33 dollars per $1000 at the initial reduction in 2010 and 0.88 to 1.05 dollars per $1000 at the final reduction level in 2015. At the final reduction level this represents a 0.088% to 0.11% decrease in the net proceeds. Similarly on the basis of the value of shipped product, the cost per $1000 is 0.13 to 0.16 dollars in 2010 and 0.41 to 0.49 dollars in 2015.

This results in an electricity cost of 0.18 to 0.23 dollars per $1000 of added value for the initial reduction and 0.65 to 0.78 dollars per $1000 of added value at the final reduction level. At the final reduction level this represents a 0.65 to 0.078% increase to manufacturing cost. The cost is lower if based on the value of shipped product.